NEW APPLICATION

0000080957

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
CHAIRMAN
JIM IRVIN
COMMISSIONER
WILLIAM A. MUNDELL
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC DIVISION OF CITIZENS COMMUNICATIONS COMPANY TO CHANGE THE CURRENT PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE RATE, TO ESTABLISH A NEW PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE BANK, AND TO REQUEST APPROVED GUIDELINES FOR THE RECOVERY OF COSTS INCURRED IN CONNECTION WITH ENERGY RISK MANAGEMENT INTIATIVES.

DOCKET NO. E-01032C-00-0751

APPLICATION

The Arizona Electric Division ("AED") of Citizens Communications Company ("Citizens") submits this application to the Arizona Corporation Commission seeking approval (i) to change the current Purchased Power and Fuel Adjustment Clause ("PPFAC") rate, (ii) to freeze and amortize over a period of three years the balance in the existing PPFAC Bank as of September 30, 2000, (iii) to establish a new PPFAC Bank that would track power supply costs prospectively based on a twelve-month rolling average basis, and (iv) to begin accruing carrying charges on the accumulated balance of over or under-recovered power supply costs.

The AED is also requesting approval to implement energy risk management initiatives intended to improve rate stability by reducing the volatility of power supply costs associated with competitive wholesale power markets. The AED asks that the Commission establish guidelines that would be applied to recover costs associated with the implementation of these initiatives.

Finally, the AED asks that the Commission issue any approvals needed in connection with proposed billing initiatives designed to minimize the impact of increased electric bills.

I. **BACKGROUND**

Citizens is a Delaware corporation with operating divisions and subsidiaries providing telecommunications, energy and water utility service to more than 1.9 million customers in 22 states. The AED serves some 70,000 customers in Mohave and Santa Cruz Counties. The AED's last electric rate case was based upon a March 31, 1995, test year, with new rates effective January 1, 1997.

The AED is primarily an electric transmission and distribution utility. Its only generation capability is a 45 MW combustion turbine facility in Nogales, which serves to provide capacity to backup the long radial transmission line serving Santa Cruz County and to reduce power supply costs through capacity credits from Arizona Public Service Company ("APS"). The customers of the AED are located in and around three distinct areas – the City of Kingman, Lake Havasu City in Mohave County, and the City of Nogales in Santa Cruz County. Customers in each of these three cities, including surrounding areas, are independently served through separate transmission substations connecting the AED's sub-transmission network to the transmission grid of the Department of Energy's Western Area Power Administration ("WAPA"). WAPA's transmission grid provides the AED with access to its sole bulk power supplier, APS.

As stated, the AED is a generation-dependent utility. For nearly thirty years, with a few minor exceptions, its sole power source has been a full requirements contract with APS. Power supply expenses have been recovered by the AED through the power cost component of basic service rates and the operation of the Purchased Power and Fuel Adjustment Clause, as more fully explained later. Under the traditional regulatory paradigm in Arizona, this arrangement has served the AED and its customers well. The AED has been afforded a reasonable opportunity to recover its purchased power expenses, and its customers have enjoyed relatively stable and economical rates. In recent months, however, this historical pattern has abruptly and significantly changed.

With the onset of the warmer summer months, the AED has experienced increases in its monthly power bills ranging from 50% to more than 100% greater than those received in the corresponding months of prior years. This may be attributed to a variety of factors, including abnormal weather conditions, increasing demand relative to available generating capacity in this region of the Country, and the volatility associated with the deregulation that has occurred in the natural gas industry and in wholesale electric power markets.

The unprecedented power-supply-cost increases experienced in recent months are being closely scrutinized by Citizens. In addition to the normal due diligence analyses undertaken at the time monthly power bills are received, Citizens has undertaken an expanded effort to assure the bills are in accordance with the terms of the contract with APS, to identify the reasons for the higher costs, and to investigate APS historic management of its power supply obligation.

Given the magnitude of power supply cost increases currently being experienced, the traditional operation of the PPFAC would require rate adjustments of unprecedented magnitudes, causing substantial rate shock for our customers. Extraordinary costs require a non-traditional regulatory response. Accordingly, this filing contains proposed modifications to the traditional power supply cost recovery scenario, along with certain commitments intended to provide the AED a reasonable opportunity to recover its costs while, at the same time, mitigating the economic burden on current customers. Moreover, Citizens is also requesting guidance from the Commission concerning future recovery of costs incurred in connection with the implementation of certain measures intended to mitigate energy-management risk.

II. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE

As a generation-dependent electric utility, the AED receives no profit from the resale of purchased electricity. Power supply costs not recovered in basic service rates must be recovered from the operation of the PPFAC mechanism.

The Commission has long recognized the usefulness of cost recovery mechanisms by gas and electric utilities operating in the State of Arizona. As early as 1952, the AED had a rate adjustment mechanism in place that enabled it to track and recover its power supply costs. The current PPFAC procedure was approved in Commission Decision No. 49576, issued in December 1978, after a generic proceeding investigating purchased power and fuel adjustment clauses. That decision established a uniform method of reporting by affected utilities. It also provided for limited hearings after which the Commission could authorize the use of billing adjustment factors that would enable a utility to recover from or pass back to customers, the difference between fuel and purchased power costs incurred and the amounts recovered from customers. The AED is now the only investor-owned utility with a PPFAC.

A key element of the current purchased power cost recovery mechanism is the PPFAC Bank Account ("Bank"), a regulatory asset used to reconcile power costs and recoveries. All power purchases are charged to the Bank and all power cost recoveries are credited to the Bank. The remaining balance in the account represents the cumulative over or under-recovery of power supply expenses.

Under the traditional PPFAC procedure, a projection of power supply costs for the next six months is required to be included in the standard monthly report filed with the Commission Staff. If such projections indicate an increase or decrease in power supply costs of one mill or more, the Staff is to recommend to the Commission that a hearing be held to consider an appropriate change to the existing PPFAC rate.

In Decision No. 62094, issued in November 1999, the PPFAC procedure for the AED was modified so that the existing one-mill threshold was replaced by an equivalent Bank balance trigger of $2,600,000. When the absolute value of the Bank exceeds $2,600,000, the AED is required to either file for a rate adjustment or contact the Commission Staff to discuss why an adjustment would not be appropriate.

Over the years, the PPFAC mechanism has worked well for the AED and its customers. On a number of occasions, increases or decreases to the PPFAC rate were approved by the Commission, as were refunds to customers after extended periods during which the costs of purchased power declined to levels below that implicit in basic service rates. However, especially given recent events, the PPFAC cannot continue to be effective in its current form as the electric industry in Arizona moves to fully deregulated generation.

The current basic service rates of the AED reflect an average power supply cost of 5.194 cents-per-kilowatt-hour ("kWh"). That includes 4.802 cents-per-kWh for electric generation and 0.392 cent-per-kWh for the cost of transporting power over the transmission lines of the WAPA. Since December 1999, the AED has been reflecting on customer bills, the 0.553 cent-per-kWh credit PPFAC factor that was approved by the Commission in Decision No. 62094. The credit includes a cumulative over-recovery in the Bank exceeding the $2.6 million threshold, plus the prospective annual savings associated with certain negotiated reductions in demand charges on the APS power bills, which will be explained in greater detail later. In accordance with Decision No. 62094, the credit is scheduled to be reduced from 0.553 to 0.297 cents at the end of November 2000, when the entire over-recovery was projected to be returned to customers. In actuality, due to higher sales in recent months, Citizens projects that all but approximately $42,000 of the original bank balance amount will be returned to customers by the end of October. Therefore, if the current rate of refunding continues through November as originally scheduled, Citizens projects there would actually be an over-refunding of some $179,000.

As of April 30, 2000, the balance reported in the Bank was $2.2 million over-recovered, all being returned to customers via a portion of the 0.553 cent-per-kWh credit PPFAC factor previously described. During May, there was a dramatic change in the Bank due to unprecedented power supply costs. As indicated on accompanying Exhibit No. 1, which is a copy of the Report FA-1 included with Citizens' May PPFAC filing, the AED's power supply costs skyrocketed to more than 11.4 cents-per-kWh. With the current recovery through basic service rates and the PPFAC factor netting only 4.6 cents-per-kWh, the Bank balance that began as a $2.2 million over-recovery became a $3.6 million under-recovery by month end.

That trend has continued in the ensuing months. Power bills from APS for June and July were $16.1 million and $19.3 million, respectively, representing per-kilowatt-hour costs in excess of twelve cents. This trend is expected to continue through the month of September. To put such amounts into perspective, the average cent-per-kWh power supply costs for June, July, August, and September of 1999 were 4.67, 4.65, 4.78, and 4.96, respectively. By the end of September, Citizens projects the under-recovered balance in the Bank to reach $52.3 million. For comparisons, in the entire calendar year 1999, the AED's total purchased power and transmission expense was $56 million, with operating revenues just under $99 million.

To the extent the existing power cost recovery procedure continues in its current form, as indicated on Exhibit No. 2, the balance in the Bank is projected to grow to nearly $57 million by the end of next May. As part of this application, the AED is asking to immediately discontinue the current 0.553 cent-per-kWh credit on customer bills. It makes no sense to continue to pass on a one-half cent credit when current power supply costs exceed current recoveries by more than seven cents.

Still, discontinuing the credit is not enough; the projected effect of discontinuing the current PPFAC credit factor is relatively insignificant. As shown on Exhibit No. 3, to the extent the credit ceases as of the end of September, the projected balance at the end of May 2001 is reduced by only $2.5 million to a level of about $54.1 million.

Under the traditional application of the PPFAC mechanism, when a utility's Bank was under-recovered by more than the established threshold, the Commission has generally allowed it to adjust its PPFAC factor to allow recovery within six to twelve months. As shown on Exhibit No. 4, a PPFAC rate in excess of 7.5 cents would be required to fully recover the Bank balance by the end of May 2001. The imposition of such a PPFAC adjustment factor would create tremendous rate shock for the AED's customers. Citizens is not requesting approval of such a rate, but includes the exhibit in this filing for informational purposes and to demonstrate its concerns about the continuing feasibility of the traditional PPFAC mechanism. Alternative recovery scenarios are clearly needed.

In October 1998, the Commission issued Decision No. 61225 after a generic investigation of the Purchased Gas Adjustors ("PGA") being used by the local distribution companies ("LDCs") in Arizona. Unlike the standard PPFAC mechanism being used by the electric companies, the PGAs were more company-specific. The genesis of the PGA inquiry was that during the two previous winter heating seasons, the Commission had received numerous complaints from natural gas customers about their monthly gas bills fluctuating greatly from month-to-month. This was largely attributed to significant spikes in the price of gas plus the fact that most of the LDCs' PGA rates reflected the current month's cost of gas. The Commission's decision included several changes to the existing PGA mechanism intending to standardize the approach used by all companies and to recognize the volatility in market prices being experienced as a result of the Federal deregulation that has occurred in the natural gas industry.

These changes to the PGA mechanism included:

- Freezing of the existing PGA Bank balances with recovery or repayment over twelve months;
- Creating a new PGA Bank account;
- Using a twelve-month rolling average for the cost of gas;
- Establishing new thresholds for the LDCs' PGA Bank balances;
- Allowing monthly changes to the PGA rate without a Commission hearing, subject to a seven cent per therm change limit over any 12-month period; and
- Accruing carrying charges on the PGA Bank balance.

Many of the same concerns that the Commission addressed in modifying the PGA mechanism now need to be addressed in the current PPFAC mechanism during the transition to electric generation competition.

The PGA decision also reflects the Commission's most recent published thoughts about the use of automatic cost recovery mechanisms to recover commodity supply costs incurred in a deregulated energy market. Accordingly, Exhibit No. 5 was prepared to ascertain the effect on the AED and its customers to the extent the new PGA mechanism was also used for PPFAC purposes. As shown on Exhibit No. 5, adoption of the PGA approach to electric power supply cost recovery would require a total PPFAC factor ranging from 4.9 to more than 8 cents-per-kWh over the next twelve months. Citizens is not requesting adoption of the PGA approach; the exhibit is presented only for informational purposes.

As has been shown, traditional operation of the PPFAC mechanism will adversely affect both the AED and its customers. For the AED to recover its power supply costs in a timely fashion, unprecedented, immediate increases in customers bills would be necessary causing significant rate shock and economic hardship for our customers. As more fully explained later in this application, Citizens is requesting Commission approval of a plan that varies from the traditional PPFAC approach, and that has both rate and non-rate elements intended to afford the AED a reasonable opportunity to recover its power supply costs while mitigating the current economic impact on its customers.

III. AED POWER SUPPLY

A. Power Supply Arrangements Through 1995

The AED has historically procured essentially all of its power supply requirements under wholesale purchased-power contracts subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC") and its predecessor, the Federal Power Commission. Before 1971, the sole source of electricity for AED's customers was the Arizona Power Authority. Since the expiration of that agreement on December 31, 1970, APS has supplied almost all of the AED's power needs under long-term agreements for firm power and energy.

In 1995, at the time of the last AED rate case, Citizens had just renegotiated its contract with APS. Negotiations lasting more than a year were directed at developing a comprehensive agreement designed to encompass all of the AED's load and resource requirements. The AED service territory had been experiencing, and continues to experience, a relatively rapidly growing load. Citizens' principal objective in the negotiations was to obtain greater flexibility while reducing costs.

The negotiations resulted in a new APS Power Service Agreement ("PSA") that included Service Schedules A, B, C, and D. It superceded all prior contractual arrangements. New Service Schedules A, B, and C addressed the AED's explicit requirements for base load capacity, intermediate load capacity, and non-firm peaking energy, respectively. Schedule D focused on future resource planning matters.

The new Service Schedule A provided 100 MW of firm base load capacity, thereby enabling the AED to access all the resources available to APS. It effectively mirrored APS' total system mix, comprised predominately of nuclear and coal-fired generation. Schedule A also included fixed pricing through May 1998, guaranteed fuel diversity, and made available an additional 50 MW of firm, low cost, off-peak energy.

Under the new Service Schedule B, APS agreed to perform an after-the-fact dispatch, on a month-to-month basis, to optimize purchases under the three APS service schedules. Only the capacity and energy from Schedule B that is required would be utilized. New capacity and energy pricing terms under Schedule B were firm through May 1998. Such contract pricing, combined with the after-the-fact dispatch and lack of purchase minimums or maximums, made the new Service Schedule B a more flexible, cost effective match to the AED's system requirements.

New Service Schedule C was intended to provide peaking energy. A key element of this part of the APS contract was the establishment of a capacity credit for the AED's Valencia gas turbine and diesel generating facility in Nogales.

Service Schedule D set forth the terms and conditions for integrating the Nogales generation and future planned generation capacity for the AED with that owned by APS, as more fully explained below.

B. <u>Power Supply Arrangements Since 1995</u>

Since the signing of the APS PSA and associated Service Schedules in 1995, Citizens and APS have engaged in a number of contracting activities, including execution of a Resource Integration agreement under Schedule D and a Power

Purchase Agreement, and have also on-going contract discussions on the pricing and terms of the power supply arrangements between the parties. A significant factor in these discussions has been the development of new generation resources in the AED's service area by competitive power developers. APS contract discussions have led to agreements (or pending agreements) to modify the PSA in four key areas: (i) a reduction in the demand charges under Service Schedule A; (ii) a refund to settle disputes about billing procedures; (iii) an agreement to allow reductions in Schedule A contract demand levels; and (iv) a restructuring of pricing for the PSA Service Schedules.

1. **Resource Integration and Power Purchase Agreements**

Facing the need to meet growing electric demand in Mohave County, Citizens undertook two essentially parallel efforts in the mid-1990's. First, Citizens prepared and issued a Request-for-Proposals ("RFP") for energy and capacity to meet its forecasted local resource needs. Second, recognizing the growing complexity of effectively managing an expanding portfolio of electric generation resources, combined with the possibility of achieving economic synergies, Citizens pursued a new operational agreement addressing its existing and planned generation resources with APS. Under Schedule D, APS would integrate Citizens' generation units into its electric dispatch operations so that it could maximize operational efficiency by serving Citizens' load requirements using power and energy supplied by APS' system or by dispatching one or more of Citizens' generation units, based on the most economic result. In response to the RFP, APS submitted a proposal to build a 75 MW simple-cycle combustion turbine facility at a site in Mohave County and to enter a long-term agreement with Citizens for the purchase of the electric output of that facility. APS' proposal was ultimately selected as the winning bid, and an agreement was executed. The terms of the resulting business arrangement included: (i) amending Service Schedule D – Resource Integration to accommodate the APS gas turbine facility in Mohave County; (ii) executing a Power Purchase Agreement (a 20-year agreement for Citizens' purchase of the plant's output); and (iii) amending the provisions of Service Schedules A and B. The amendments to Schedule A allowed Citizens to increase its access to off-peak energy, while the amendments to Schedule B modified its contract term and termination provisions.

In mid-1998, the construction of a 650-MW, combined-cycle, generation station in Mohave County, ultimately known as the "Griffith Energy Project," was initiated by PP&L Global, a competitive power development arm of Pennsylvania Power & Light. This new power facility would require transmission facilities to transport its output into the western electric markets. At the time, Citizens was beginning to consider the feasibility of constructing transmission facilities to carry the power from the planned APS combustion turbine plant tying into both the Kingman and Lake Havasu City load centers. The new transmission line was expected to use a corridor passing very near the site being proposed for the Griffith project. Given their common interests surrounding new electric transmission facilities in Mohave County, Citizens and the project developers worked closely together to seek mutually beneficial solutions. The siting of the Griffith Project in Mohave County and the planned construction and reinforcements to local transmission facilities effectively addressed Citizens' near-term transmission requirements and would eliminate the need for the planned APS' generation facility anticipated under the Citizens/APS Power Purchase Agreement. Moreover, Citizens' already-permitted transmission corridor between the proposed APS plant site and Kingman was of value to the Griffith developers to affect the needed transmission improvements. Consequently, Citizens undertook two actions in late 1998/early 1999 that significantly reduced its costs that were potentially stranded when its service territory opens to retail competition.

First, Citizens decided to cancel the APS Power Purchase Agreement, even though doing so subjected it to potential cancellation costs of approximately $1.85 million.[1] This amount was far less than the potentially stranded costs (estimated to be $6.7 million) that would likely occur if the facility were built as planned. Second, Citizens sold its rights-of-way and environmental permits associated with the northern portion of the planned transmission corridor to Griffith for $1.5 million. Citizens retained the southern portion of the corridor for other transmission projects that may be needed to meet future customer requirements. In total, this action by Citizens eliminated approximately $2.1 million of potentially stranded transmission-related investment. In the aggregate, this action by Citizens reduced its potentially stranded costs by nearly $9 million.

2. **Recent Contract Negotiations**

In 1998, Citizens also pursued contract discussions with APS focusing on the pricing and terms of the PSA and its Service Schedules. The initial focus concerned the base load portion of the PSA, Schedule A, and ultimately led to a reduction in Schedule A's demand charges. The Stipulation of Charges under Service Schedule A to the PSA, as negotiated in January 1995, included a provision that gave either party the right to make an application to the FERC, after May 31, 1998, to request modifications to Service Schedule A. More importantly, that provision included the limitation that: "...in the event of such application, APS shall not propose a composite charge greater than that which would result from the use of an embedded cost methodology based on the cost of APS' system." Accordingly, in early 1998, Citizens and APS commenced discussions about the charges under Service Schedule A and their relationship to APS' embedded cost. After several months of discussions and data analysis, the

[1] Ultimately, APS elected to retain rights to the combustion turbine associated with the Power Purchase Agreement for its own use and agreed to waive any cancellation costs.

parties agreed in early 1999 to lower the Schedule A charges retroactively, in four steps, beginning with August 1, 1998, and running through January 1, 2001. Through the entire period of the modified agreements ending April 30, 2002, these reductions were projected to save the AED's customers nearly $13 million.

In May 1999, shortly after the negotiations that produced the Schedule A demand charge reductions was complete, Citizens was notified by APS of a billing error that had been made during the period January – November 1998, resulting in approximately $4.3 million additional payments due. Due to the magnitude of this additional payment request, Citizens initiated an investigation into the underlying facts and circumstances, a process that began in summer 1999 and ensued for several months.

While that billing investigation was underway, Citizens was notified that APS, Pinnacle West Capital Corporation, and APS Energy Services Company (collectively "Pinnacle West Companies") intended to make a filing at the FERC containing, among other things, a request to modify the PSA with respect to the Price Ceiling and Minimum Rates provisions. The principal intent of the FERC filing was to seek approval for the Pinnacle West Companies to engage in inter-company, affiliated transactions at market-based rates. As part of this filing, the Pinnacle West Companies were required to address a concern that its wholesale customers, including Citizens, would not be adversely affected by potentially abusive inter-affiliate transactions. The part of the filing directly affecting the PSA, which was ultimately approved by FERC, effectively capped certain energy pricing components based on the Dow Jones Palo Verde Index ("PVI") prices. Under the former contract language, minimum pricing was tied to APS' system incremental cost ("SIC"). Under the new language, the minimum pricing for wholesale power transactions became the lesser of charges developed based on APS' SIC or the PVI prices.

In addition to discussions concerning the APS billing revision for 1998, and the pending market-based rate filing before the FERC, Citizens was also engaged in discussions with APS on modifying the PSA to accommodate retail open access. Key points under discussion included the procedure to disaggregate competitive retail load data from the total metered load billable to Citizens, in order to establish the cost to serve its Standard Offer customers, and the impact of the fixed 100 MW Contract Demand under Schedule A on Citizens' power costs, as existing retail load migrated to competitive suppliers.

Given the multitude of issues being addressed by the parties at the time, APS and Citizens sought to craft a comprehensive agreement that would settle all the key matters under discussion. In May 2000, the parties signed a Memorandum of Understanding to serve as the framework for a comprehensive settlement agreement. The general points of such an agreement would include:

- APS would refund $1.5 million to settle outstanding billing issues;
- Citizens would not file a protest in the Pinnacle West Companies' FERC filings and would withdraw its then-current intervention;
- The parties would alter the existing PSA to accommodate competitive retail power deliveries;
- Citizens would be able to reduce the Schedule A Contract Demand, after May 2002, based on net load loss resulting from retail competition; and
- The parties would restructure certain Service Schedules to the PSA and tie pricing to 1999 actual power costs, indexed to the change in natural gas prices.

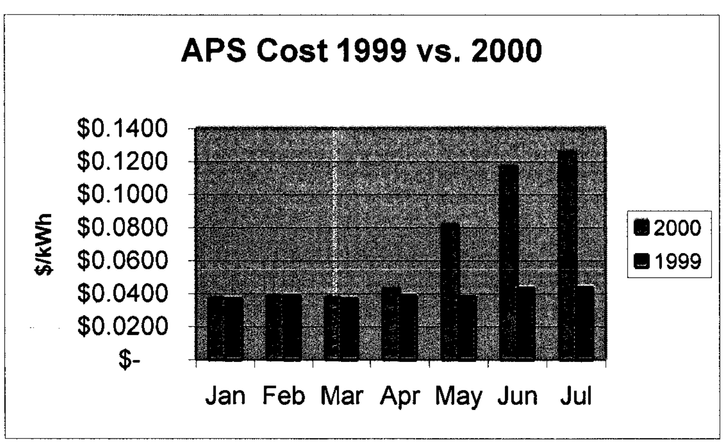
As a result of the uncertainty that has now arisen due to the unprecedented power supply cost increases reflected in the bills received from APS during the past three months, Citizens and APS have not yet finalized the comprehensive agreement, and it remains pending as of the date of this filing.

IV. UNDERLYING CAUSES OF SUMMER 2000 POWER COST INCREASES

This section of Citizens' application describes the substantial increase in power costs that Citizens has experienced this summer and discusses the underlying causes. As shown below, Citizens' costs for APS power deliveries for the May – July period have risen over 160% on a $/kWh basis. Citizens believes the Summer 2000 power cost increases are attributable to the interplay of five key factors: (i) the significant increase in natural gas prices thus far in 2000; (ii) growing electric demands in the Western United States relative to existing generation resources; (iii) the impact of the deregulation of the wholesale power markets, especially in California; (iv) APS' power resource capability relative to its native load; and (v) the Minimum Rates provisions of the Citizens/APS Power Service Agreement and associated Service Schedules. The following discussion identifies the various factors that have contributed to substantial increases in the wholesale cost of power.

A. Summary of Summer 2000 Power Cost Increases

As of the preparation of this filing, Citizens had received bills from APS for power supplied through July 2000. The following chart illustrates, on a $/kWh basis, the comparative charges from APS for 1999 versus 2000. As can be seen,



while prices for the months of January through April were comparable, those implicit in the APS bills for the months of May through July were approximately

100% to 150% higher in 2000 than 1999. The portion of the total amounts paid for power during May – July 2000 solely attributable to higher APS commodity costs this year exceeded $27 million. Citizens is projecting that, for the entire Summer 2000 cooling period from May through September, the increased price for APS power deliveries will produce more than $51 million higher power bills. To put this in perspective, the <u>total</u> APS power costs for all of 1999 were $50.2 million.

B. <u>Increase in Natural Gas Prices</u>

Natural gas not only fuels a significant portion of APS' generation, but also fuels a sizeable portion of power plants operating throughout the western United States. Moreover, it is the fuel that will be used for essentially all planned generation facilities to be constructed in this region for the foreseeable future. In the summer of 1999, the commodity price for natural gas available to western generation facilities was typically in the range of $2.50 – $3.50 per million BTU. This summer, price levels have risen to the range of $3.50 – $5.00 per million BTU, a 30 – 50% increase. The generation resources used by APS to serve Citizens' peak-period loads in the summer of 2000 are in large part fueled by natural gas. However, as illustrated above, the 150%+ increases in Citizens' power costs cannot be solely attributed to the increase in natural gas prices, even if it was assumed that 100% of Citizens load was served with gas-fired generation.

C. <u>Electric Supply Versus Demand in the West</u>

Much media attention has been focused this summer on the situation concerning the cost of electricity in California, and for good reason. With peak load requirements in the order of 50,000 MW, California represents approximately 40% of the entire U.S. portion of the Western Systems Coordinating Council's ("WSCC") peak demand. Due to its large size, the impact of system and market conditions in California reverberates throughout the

Western grid. While this summer's loads have revealed an overall imbalance between electric supply and demand throughout the WSCC, the situation in California has been the dominant factor.

On August 2, 2000, the California Electricity Oversight Board and Public Utilities Commission jointly submitted a report to the Governor's Office on the various power issues faced by the state, particularly the unprecedented increases in consumers' electric bills. Entitled "California's Electricity Options and Challenges," the report analyzes the circumstances giving rise to the curtailments, blackouts, and pricing problems facing California. Among the subject areas covered is the lag of electric capacity additions relative to load growth. Of the 55,500 MW of generation capacity on-line in California, only approximately 670 MW, or less than 2%, was added between 1996 and 1999. During the same time frame, peak load has grown by over 5,500 MW. The State currently requires power imports of an additional 8,000 MW to meet its peak requirements. As a consequence of the current gap between supply and demand in California, electric reliability was significantly compromised on several days during this summer. The California Independent System Operator ("CA-ISO") declared Stage Two Emergencies (operating reserves less than 5% of expected load) on 12 separate days this summer (through 8/17/00). On June 14, 2000, Pacific Gas & Electric was required to interrupt nearly 100,000 of its customers in the San Francisco Bay Area, an unprecedented event precipitated by high loads and short supply in that area.

Further, the squeeze on power supplies in California has caused massive increases in the price of electricity. Since 1995 and the deregulation of wholesale electric markets by FERC, the wholesale price of electricity has varied according to the fundamental economic principles of supply and demand. Until this summer, the traditional regulatory system served consumers well. As reported in <u>California's Electricity Options and Challenges</u>, this year, between June and

August, wholesale prices for electricity in California increased on average 270% over the same period in 1999. Further, during a single week in June, purchasers of California power spent $1.2 billion on electricity, an amount equal to 1/8 of their total cost of power in 1999.

As the dominant player in the western electric markets, the events in California spilled over into neighboring states. For instance, the weighted average price of firm on-peak electricity at the Dow Jones Palo Verde Index trading hub averaged $.165/kWh, $.150/kWh, and $.222/kWh, for June, July, and August 2000, respectively and hit daily highs of $.517/kWh, $.334/kWh, and $.519/kWh in those same periods. Such prices vastly exceed those experienced at the Palo Verde hub at any time in its history.

D. Deregulation of Wholesale Power Markets

The extraordinary price levels experienced in western wholesale electricity markets during summer 2000 would not have occurred under traditional wholesale price regulation. Prior to the issuance of FERC Order 888 in 1995, which deregulated wholesale markets for electricity, rates for wholesale electric generation service were set and/or reviewed on the basis of the embedded cost of service. That is, an electric utility making wholesale power sales would be allowed to recover through rates its prudently incurred cost of providing service (expenses, taxes, labor costs, etc.) plus a fair rate of return on prudent investment in property, plant, equipment, materials and supplies. Such pricing was usually established in one of five forms:

1. **Average System Rate** – a rate that recovers average fixed costs of all generating units on the system in a demand charge and average system variable costs in an energy charge. This rate structure was commonly used in requirements contracts;

2. **Off-System Rate** – a rate that recovers the fixed costs of selected units most likely to provide the service in a demand charge and 100% - 110% of the incremental cost of the system (fuel and variable costs or purchased power costs) in an energy charge;

3. **Unit Sale Rate** – a rate that recovers fixed and variable costs of a particular generating unit through demand and energy charges;

4. **Total Revenue Constraint Rate** – a three-part rate with a ceiling price based on the fixed and variable costs of the most expensive unit on the system, a negotiated demand and energy charge, and a floor price equal to system incremental costs;

5. **Emergency Rate** – a rate equal to the higher of 110% of system incremental cost or a FERC-specified ceiling ($30/MWh raised to $100/MWh in the late 1980's).

FERC has required that all pricing forms except the Average System Rate utilize a "floor" (the allowed minimum price) equal to the system incremental costs, reflecting the fact that most fuel costs included volatile commodities, such as oil and gas. The use of a floor provided assurance that the seller would charge rates that would at least recover the incremental variable costs, and that the seller's other customers would not subsidize the sale through the operation of its fuel adjustment clause.

Accordingly, under cost-based rates, unless the seller owned an expensive nuclear unit, the highest rates would be the emergency energy rate of $100/MWh or 110% of the seller's incremental costs. The incremental costs could include purchased power costs, since typically a utility would only purchase power if that were less expensive than operating one of its more expensive generating units or constructing a new unit. Under FERC policy, however, a utility may only recoup 100% of the purchased power costs incurred plus an adder equal to one mill/kWh. This limitation insured that power was not sold and then resold to increase the rate that could be charged for the power. Moreover, the FERC required a fixed, rather than a percent, adder to reflect the fact that the utility's costs of negotiating a power purchase should be independent of the price. Under the traditional regulatory paradigm, utilities normally provided for sufficient long-term capacity, either owned or purchased, to meet their peak load and reserve requirements, including wholesale sales. Accordingly, utilities normally purchased power only when it was economical or in emergencies, such as during the loss of a large generating unit.

The advent of the deregulation of wholesale electricity markets brought two significant changes to the functioning of the industry. First, the cost-basis approach to pricing wholesale sales was no longer applicable; as long as a utility could demonstrate to FERC that it did not have inordinate market power, it could sell power at prices dictated by what the market would bear. The key underlying assumption is that the market will discipline wholesale prices. Second, utilities began reducing their reliance on their own generation and began buying power from other utilities or markets rather than building their own units and incurring the additional risk of potentially unrecoverable costs.

The runaway electric prices that occurred in California wholesale electric markets and spilled over into adjoining regions during the summer of 2000 were made possible in part because of the wholesale electricity deregulation. This summer's events have led the FERC and various California State agencies to investigate the underlying causes, although they may not be fully understood for some time. However, the California's Electricity Options and Challenges report suggests that the rules directing the California wholesale market are in fact flawed and that market participants are able to game the system to their benefit even while obeying the rules.

Currently, California law requires that utilities serving the vast majority of California customers purchase all their power requirements through the CA-ISO and California Power Exchange ("PX"). In simplified terms, the PX conducts a day-ahead auction among participating generators and buyers for the hourly supply of electricity to meet California's electric demands. The PX sets the hourly price to be paid to all sellers at the highest price bid for that hour. During the following day, the CA-ISO, which controls the transmission system, directs the flow of electricity throughout the state. If the power supply purchased in the PX is not sufficient to meet electric demand, the CA-ISO makes up the difference by purchasing additional electricity to balance the load and meet reserve levels. This latter market operated by the CA-ISO is known as the "Ancillary Services Market" and consists of a number of generation products that enable the CA-ISO to instantaneously balance supply with load.

While the CA-ISO has implemented certain pricing caps, its mission to maintain the electric system is not generally constrained by the cost of power, and its real-time markets often command very high prices for the electricity that is needed immediately to keep the system operating. Among other suggestions about market participant behavior, the California Report suggests that sellers may have been withholding power from the day-ahead PX market in order to drive up prices in the CA-ISO real-time markets, particularly the "Replacement Reserves" market.

While all the facts are not yet in, it appears that the deregulation of wholesale electricity markets in conjunction with potentially flawed market rules in California have been key factors underlying this summer's skyrocketing power prices.

E. <u>APS' Load/Resource Balance</u>

As identified previously, one consequence of the deregulation of wholesale electricity markets has been heightened concern about potential stranded costs that has in turn discouraged utilities from building new generation to meet their load and reserve requirements. Instead utilities are becoming increasingly reliant on power purchases in the wholesale market to meet their needs. This response has in part led to the current gap between supply and demand existing in the western grid. It appears that, instead of maintaining the system generation that has traditionally supported its service to Citizens, APS has also switched to the wholesale markets. Consequently, because the Citizens/APS contract is based on

APS system incremental resources, during the summer months (with demand at highest levels) APS served a significant portion of the AED's load from short-term or spot purchases made in the competitive markets. These were the very power resources that experienced this summer's unprecedented price run-ups.

F. <u>Contract Pricing Provisions</u>

The APS/Citizens PSA and associated Service Schedules are of the basic form of a Total Revenue Constraint Rate, as described in the section above on the Deregulation of Wholesale Electricity Markets (however, certain elements are based on average system cost). That is, the contracts consist of three key elements: a price ceiling, based on the fixed and variable costs of the most expensive unit on the system (the Palo Verde Nuclear Station and other APS resources); a negotiated demand and energy charge; and a floor price equal to system incremental costs. These elements of the contracts are set forth in the current Service Schedules A, B, & C, as summarized below:

Service Schedule A:

Citizens purchases 104 MW under a system average rate form:

Customer Charge: $523/Month

Demand Charge: $14.75/kW-Month

Energy Charge: $.01676/kWh

Citizens also purchases additional off-peak energy at a rate of $.01676/kWh plus a 15% adder, or APS' system incremental cost plus a .0015/kWh adder, whichever is higher.

APS' **System Incremental Cost** is defined as:

> The higher of either the incremental fuel cost of the station or unit from which energy is obtained, estimated over the applicable range of output as dispatched; or the cost of any purchased power occurring simultaneously with sales under this Service Agreement which were made for economic purposes and would not otherwise be needed to effect transactions under this service agreement. In

addition, there is the cost to start up additional units and other incremental costs such as incremental maintenance, third party transmission, taxes, etc.

Service Schedule B:

Citizens purchases on-peak energy above the Schedule A deliveries, but below Schedule C deliveries, under Schedule B:

Demand Charge: $4/kW-Month

Energy Charge: the lower of 115% of APS' system incremental costs, 115% of current market price, or the cost of purchased power.

Service Schedule C:

Citizens installed combustion turbines ("CTs") near Nogales to enhance system reliability; it receives a capacity credit equal to 85% of the continuous output capacity of the CTs. Citizens pays:

Customer Charge: $1000.00 per month

Fuel Charge: 120% of APS' highest hourly incremental fuel or purchased power costs for the day times the energy provided by APS

O&M Charge: Based on the O&M costs of APS' CTs

The Minimum Charge is the sum of the Customer Charge and O&M Charge.

G. Ceiling and Floor Provisions

All power delivered by APS to Citizens under Schedules A, B, and C is subject to separate ceiling and floor provisions capping the rate at the total revenue constraint rate based on Palo Verde Unit 3 and other APS resources. In addition to the rates in Schedules A, B, and C above and the ceiling rates, there is also a floor equal rate to 100% of APS' system incremental costs.

While the term "system incremental costs" is defined as previously described, the "floor" contains a statement that Citizens is responsible for purchased power costs and for any other costs incurred by APS in fulfilling its obligations for providing power under Schedules A, B, and C. Therefore, it appears that if the floor is to be equal to system incremental costs, it would include all purchases, rather than only the economic purchases provided for in the definition of system incremental costs previously identified.

Citizens' bills from APS for May, June, and July 2000 have invoked the floor and ceiling provisions of the contract for billings under most Service Schedules.

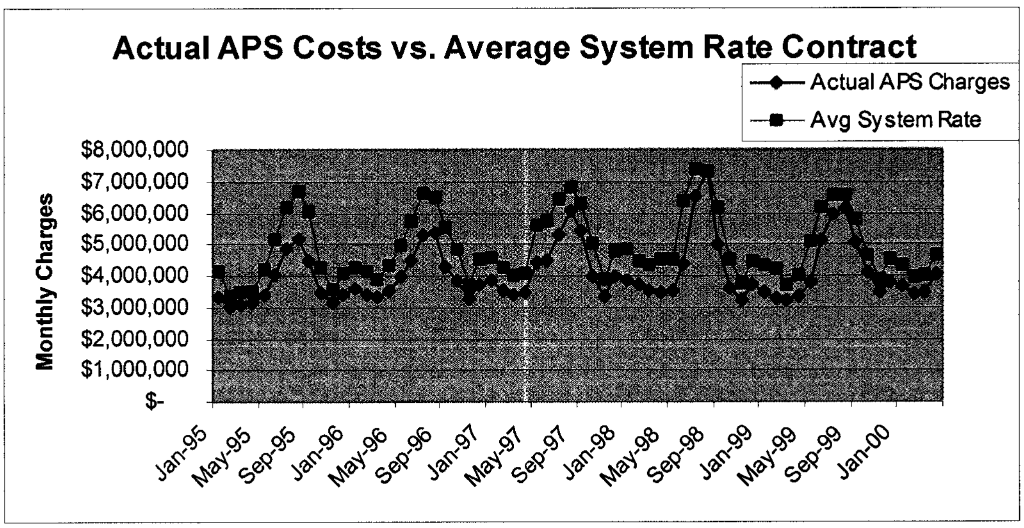
The following table illustrates the impact on Citizens of these billing provisions:

Month/Sch	Normal Chg.	Ceiling Invoked	Floor Invoked	Difference
May 2000				
Sch. A	$3,542,372		$5,378,793	$1,836,421
Sch B	$3,631,954			N/A
Sch C	$ 491,939			N/A
June 2000				
Sch. A	$4,109,774		$7,240,006	$3,130,232
Sch B	$7,000,551		$7,581,611	$ 581,060
Sch C	$1,682,575	$1,259,174		$ (423,401)
July 2000				
Sch. A	$2,831,345		$8,978,311	$6,146,966
Sch B	$5,127,479		$8,300,996	$3,173,517
Sch C	$1,543,369		$2,719,541	$1,176,172
Period Total	**$29,961,358**	**$1,259,174**	**$40,199,258**	**$15,620,967**

The implication here is that, while prices this summer were very high under normal billing rates, the imposition of the ceiling and floor pricing provisions increased them even further, adding an additional $15.6 million to the total charges for May through July. Such additional charges result from the floor pricing that includes all purchases, not just economic purchases, as is the case under the normal rate calculations.

It is clear that the Citizens/APS contract has provided stable and economic rates to Citizens' customers up to the summer of 2000. Notwithstanding the above analysis, Citizens' customers have received electric bills reflecting the large savings historically associated with Schedules A, B, & C, as a result of purchasing power at APS' system incremental costs, as compared to what would have occurred had all power purchases been under an Average System Rate contract.

The comparative costs for the two types of contracts can be demonstrated by comparing actual billings to the charges that would have been billed if all energy and demand were priced under Schedule A rates, reflecting APS' average system costs. For the period January 1995 – April 2000 (the period of the current contract to date), the savings to Citizens from having secured an incremental-cost versus an average system cost agreement with APS are positive for every billing month as illustrated in the graph below.



A similar comparison for the summer 2000 would not show a result this favorable. Nevertheless, since the signing of the current system-incremental-cost contract in 1995 through the beginning of this summer, Citizens has saved approximately $43 million in power supply costs, as compared with pricing under an average system cost contract with APS.

The summer of 2000 brought with it unprecedented prices for wholesale power in the Western grid that resulted from significant increases in the cost of natural gas, a shortage of generation supplies relative to electric demands, and a deregulated wholesale marketplace exacerbated by potentially flawed rules in the California electric market, the most significant factor influencing the WSCC. Such high power prices affected Citizens as a result of its APS contract based on system incremental costs and APS' increasing reliance on market purchases to meet its native load requirements. The APS contract has historically served

Citizens well over the years with economical power prices and a regulated environment, but as a result of the dramatic changes occurring in the restructured electric industry, it may no longer be a viable source of power for Citizens' customers.

V. <u>REVIEW OF APS BILLS</u>

To insure that Citizens has been properly billed for power from APS, Citizens has initiated an in-depth analysis of all relevant billing data, of the procedures used for computing charges reflected on the APS bills received this summer, and of the generation resources used to serve Citizens' load. The principal objectives of the inquiry are to definitively establish that all charges are in accordance with the APS PSA, to ascertain clearly the reasons why the bills are significantly higher this summer, and to ensure that the resources employed by APS to serve the AED were the least cost available. The initial scope of the analysis included the months of May and June 2000. The review will ultimately include a thorough analysis of each hour of each month of the summer billing periods to evaluate the underlying components of the bill calculation.

Citizens' investigation of the APS data is being undertaken in three phases. Phase I, already complete, entailed a reconciliation of data obtained from various APS electronic and manual entry sources in order to establish a preliminary determination with respect to the probable causes of the higher-than-expected power bills, to minimize the data accumulation requirements imposed on APS, and to enable Citizens to become more rapidly focused in its analysis of the data. From the APS data acquired and reviewed thus far, Citizens has already created a dispatching hierarchy analysis determining which APS resources (owned and purchased) were used to meet total load, including that of Citizens, and sales to other parties. The data includes APS' manual and electronic pricing logs for sales and purchases, the dates the sales and purchases were entered into, unit availability and performance characteristics, day-ahead load estimates and actual loads, reserve requirements, and any transfers between the APS load desk and the APS marketing desk. The results of Phase I indicate that APS' calculations of the costs of its own units did not differ materially from Citizens' calculations, and that APS was in fact required to purchase energy to meet its peak load on the two days of highest usage. Under the rate provisions of the contract, the reliability purchases should not be included in the calculation of the rate, but may be includable in the floor calculation. Citizens reviewed the purchase and sale data, including transfers of purchases and sales between the load and marketing desks of APS to determine if the transfers were done at market. Also included in the scope of the review were APS' details of the calculation of the rate, ceiling and floor under the contracts.

Phase II will involve the remaining days of the summer period and will focus on APS' purchases and sales and transfers between its load and marketing desk. Also, daily resource dispatching data will be prepared in order to determine the need for the purchases and to verify sale prices. It is contemplated that Phase II, while encompassing considerable data, can be completed within a short time after receipt of the data from APS. At the completion of Phase II, Citizens will request a meeting with APS to discuss the results of its analyses and to request explanations concerning any contract inconsistencies or other differences revealed in the audit. At the conclusion of its investigation of the power bills and meetings with APS, Citizens will share the results with the Commission Staff.

In Phase III of the audit process, Citizens will investigate the extent to which APS practiced due diligence in the acquisition of resources that served Citizens' load during the summer of 2000. This inquiry will seek to determine whether APS resource procurement strategy resulted in the lowest reasonable cost to Citizens. As confirmed by APS in a recent filing at FERC, APS no longer owns sufficient generation to meet its peak load, and therefore APS must purchase power during peak periods to meet its load requirements. As APS stated in its Protest in FERC Docket No. ER00-3312-000 at page 5 (September 5, 2000): "During peak hours, APS is a net importer of power and energy; it does not own sufficient generation to serve all of its wholesale and retail load obligations during these periods." As a result, APS is exposed to market prices for the portion of its load that exceeds its owned generation and longer-term purchases (as opposed to short-term or spot purchases).

Why APS did not construct additional generation, or enter into longer-term purchases, to cover the portion of its load that exceeds its owned generation is unknown. The DOE "Electric Utility Restructuring Weekly Update" for August 18, 2000, explains that APS had a 300 percent wholesale rate increase (citing the August 16, 2000, "Public Power Daily"). Phase III of the audit process will review this matter.

The standard for the Phase III review will be based on the forecasted short-term purchase prices and the longer-term purchase prices during the periods prior to the high market prices incurred by APS, and seek to determine what a reasonable person, after appropriate analysis of the data then available, would have concluded. Accordingly, the review of APS' prudence not to cover (own generation or enter in to longer-term purchases) all of its load will require a review of its purchase power procurement practices over the last few years. Such a review will consider: data on purchases and market data that APS relied upon in deciding what portion of its load would be covered in the short-term or spot market, and what portion would be covered in longer-term purchases or owned generation; whether APS' purchased power procurement practices met NERC reliability requirements; and whether APS' procurement practices for its marketing desk differed from that of the load desk.

VI. CITIZENS' PROPOSAL

As stated, the power-supply costs experienced by the AED in recent months are unprecedented. The traditional operation of the PPFAC mechanism to recover the shortfall between the APS power bills and the power cost component in basic-service rates would require a substantial increase in customer rates. Citizens believes that unprecedented cost increases in this instance are best addressed with non-traditional solutions. The comprehensive plan being proposed has both rate and non-rate elements, and was developed with the principal objectives of striking a proper balance between preserving Citizens' opportunity to recover its cost of providing power while mitigating the impact on current customers. The elements of this proposal are fully integrated, and any significant alteration may substantially and adversely impact the opportunity to achieve these objectives.

The remainder of this application sets forth the details of Citizens' proposed initiatives.

VII. RATE INITIATIVES

Under the traditional operation of the PPFAC, as demonstrated on Exhibit No. 4, Citizens would be requesting the implementation of a PPFAC factor of more than seven cents-per-kWh for its AED customers. Citizens believes that such an increase is not a desirable option at this time. Presently, as shown on Exhibit No. 6, except for two co-ops, Citizens' residential rates are the lowest among all electric utilities in the State of Arizona. Citizens intends to do everything it can to maintain affordable electric rates for all its customers.

In considering the various alternatives that might be used in connection with the substantial under-recovery of power costs incurred this summer, Citizens evaluated the current PGA mechanism. As previously stated, the most recent indication of the Commission's preference concerning the use of commodity cost pass-through rate adjustment mechanisms is its 1998 decision in the generic PGA proceeding. The Commission appropriately recognized that Federal wholesale deregulation has already caused volatility in the price of natural gas. To better stabilize rates, the Commission ordered the LDCs to use a twelve-month rolling average cost of gas, and recognized the feasibility of their using alternative gas procurement risk management techniques. The PGA decision also recognized that there is indeed an economic cost associated with the carrying of under-recovered or over-recovered balances in the PGA Bank.

The PGA decision provides useful guidance, but does not go far enough to address the unprecedented run-up in Citizens' wholesale electric rates. If the Commission approved a PPFAC mechanism for its AED identical to that which is now used for the PGA, an immediate change in the per-kWh adjustor factor to a rate exceeding four cents would be required, as indicated on Exhibit No. 5. Citizens prefers not to request such an increase at this time. Instead, it is requesting a change to the current PPFAC methodology to incorporate some of the features of the new PGA mechanism, but that would also produce for the time being, an adjustment rate that is more affordable for its customers.

Specifically, Citizens is requesting Commission approval to amend its existing PPFAC procedure to incorporate the following features:

- Terminating the current (0.553) cent-per-kWh PPFAC factor;
- Freezing the existing PPFAC Bank balance as of September 30, 2000, with recovery via a fixed PPFAC surcharge over a period of three years;
- Creating a new PPFAC Bank and adjustment factor with power supply costs based on a phased in, rolling 12-month average;
- Implementing a monthly accrual of carrying charges on the over or under-recovered PPFAC bank balances, based on a six percent rate of interest, compounded annually; and
- Introducing the use of energy risk management techniques and identification of the standards that would apply in establishing the prudence of such acts for cost recovery purposes.

To produce a lower fixed surcharge rate for recovering the balance of the frozen PPFAC Bank than that indicated on Exhibit No. 5, Citizens is requesting an alternative amortization period of three years, as presented on Exhibit No. 7. The Exhibit reflects actual APS power bills through July; it will be updated as the actual bills for August and September are received. As indicated on the Exhibit, the required per-kWh surcharge to extinguish the frozen PPFAC Bank is approximately 1.47 cents. The PPFAC factor for the new Bank ranges from 0.165 to 0.666 cents-per-kWh through the month of May 2001, producing an average total combined PPFAC factor of approximately 1.77 cents per-kWh during that period. Based on current annual average monthly electric consumption of residential customers in Nogales, Kingman, and Lake Havasu City, the average monthly increase would be $11.31, $11.03, and $17.08, respectively.

Two departures from the current PGA procedure implicit in the proposed PPFAC mechanism being requested by Citizens are the carrying charge rate and the carrying charge base. Both departures reduce the amounts to be ultimately paid by customers, vis-a-vis the PGA interest accrual methodology. First, the PGA mechanism allows the monthly accrual of interest on the Bank balance using the 90-day non-financial commercial paper rate reported by the Federal Reserve Bank. That rate is currently about 6.50%. For its proposed PPFAC mechanism, Citizens is requesting to use the standard 6% customer deposit interest rate for accruing carrying charges. Not only is that less than the current PGA interest rate, but it is also substantially less than the more longer term interest rates that would typically apply to the financing of a three-year investment.

The second departure from the current PGA procedure is the base upon which the interest accruals would be made. Under the PGA, interest is accrued on the month-end balance of the PGA Bank. In its proposed PPFAC procedure, Citizens intends to deduct the related balance of accumulated deferred income taxes associated with the deferred costs, before applying the carrying charge rate. This will reduce interest accruals by approximately 40%, as compared with the strict application of the PGA methodology.

Under the existing PGA mechanism, the rate adjustment factor can change monthly, subject to a change limit of seven cents per therm over any consecutive twelve-month time period. For Citizens' Northern Arizona Gas Division, seven cents represents approximately 28% of the cost of gas component in basic service rates. Given the current power supply cost in basic electric service rates of approximately 5.2 cents, a comparable change limit would be approximately 1.45 cents.

Another feature of the existing PGA mechanism is a Bank balance over or under-recovered trigger point which, when exceeded, requires Citizens to meet with Commission Staff to discuss what adjustment factor changes are warranted, if any. For Citizens Northern Arizona Gas Division, that amount was established at $4.2 million dollars. As previously stated, the existing threshold for Citizens' existing PPFAC is $2.6 million. At a time when projected power supply cost deferrals exceed previous annual purchased power expense levels, a new trigger point clearly needs to be established.

Citizens respectfully requests approval in this filing of the ability to charge the monthly combined PPFAC factor for both Banks, based on actual power supply costs without limit during the next twelve months, with a commitment to make an application to revisit, true-up, and otherwise reconsider all the elements of its requested new PPFAC mechanism at the end of that period.

VIII. Energy Price Risk Management Initiatives

With the deregulation of the generation segment of the electric utility industry, the energy price risks borne by utilities and their customers are changing. Variations in the supply and demand for electricity, combined with the recent significant increase in the price of natural gas, creates significant uncertainty regarding short and long-term prices. Historically, the industry has managed its price risks through long-term power supply contracts and cost-based economic regulation. As the industry changes, it is now necessary to explore other risk management tools. Utilities need to take a hard look at the alternatives available to effectively manage price risks and meet the demands of their customers.

Without a significant narrowing of the gap currently existing between available generation capacity and increasing customer demands for electricity in this region of the country, and some relief from the higher natural gas prices, the electric price spikes experienced this summer will likely return again next summer, and for the foreseeable future. With that in mind, Citizens is very carefully exploring ways that it may effectively manage its energy price risks. That includes fully considering all legal and regulatory avenues available with respect to the current APS PSA. It also includes identifying other power supply options and various hedging tools that may be available.

Risk management instruments are emerging in response to the deregulation of electric generation and resulting in changing power supply market conditions experienced in recent years. A well-founded energy risk management program can benefit both a utility and its customers. It can create greater rate stability and lower rates than might otherwise occur.

The principal objective of an energy risk management program should be to strike a proper balance between risk mitigation and risk taking. A key element of risk management is the use of derivative instruments for price hedging purposes. A derivative is a financial instrument that derives its value from the value of other financial instruments or an underlying asset such as a commodity, futures contract, stock, bond, currency, index, or interest rate. The main use of derivatives in risk management is to protect assets against price volatility. Among the types of derivatives appearing in the electric industry are privately negotiated forward contracts, standardized futures contracts traded on an exchange, swaps, and options. Derivatives can be a good hedge against the type of electric price risk being experienced this summer.

A key consideration in Citizens' willingness to defer the existing Bank for a period substantially longer that the traditional recovery period is its strong belief that it does have legal and regulatory options in connection with the APS PSA, and that it can, with Commission approval, successfully manage its electric price risk through the use of hedging instruments. As part of this application, Citizens asks approval to implement an energy price risk management program, a key element of which is the use of derivatives. Citizens specifically asks for guidance concerning the standards that would be imposed on Citizens at such time as it seeks recovery of the costs incurred in connection with such program. In particular, Citizens seeks guidance from the Commission on the following key questions:

- Under what circumstances is the use of price hedging warranted?
- How should utilities weigh the value of price uncertainty?
- Should hedged energy pricing be applied to all customers or only to those who select the option?
- What limits should be imposed on ratepayer exposure to risk from hedging activities?
- What standards and criteria will be applied in judging the prudence of utility hedging decisions (or decisions not to hedge)?
- What filing requirements, if any, should apply for utility risk management plans?
- What reporting should be instituted?
- Should hedging costs be recovered through the PPFAC or through base rates?

IX. NON-RATE INITIATIVES

A. Customer Initiatives

Recognizing the potentially significant impact of recovery of the PPFAC balance on its customers, Citizens has planned initiatives in communications, demand-side management, and payment terms and arrangements to assist customers to handle and potentially mitigate the pending electric bill increases.

The current plans for these initiatives are described in the following subsections.

1. Communications

Citizens' plan addresses three key areas:

- **Regular Status Reporting:** Keeping customers, media, community leaders, and employees informed about the status of the situation and key developments associated with Citizens' filing to request recovery of its uncollected purchases power costs.
- **Ensuring Accurate Information:** Addressing and clarifying any misunderstandings or customer confusion regarding Citizens' electric operations and the manner in which the AED purchases electric power.
- **Program Support:** Providing ongoing support to energy-savings programs and other payment-focused customer assistance initiatives.

To accomplish these goals, Citizens has allocated the human and monetary resources needed to move forward on a number of communications fronts. The following table indicates the principal types of communications Citizens is planning to employ for each of these communications goals.

Form of Communications	Regular Status Reporting	Ensuring Accurate Information	Program Support
Press Releases	✓	✓	✓
Press Conferences	✓		
Customer Service Training	✓		
Employee Meetings	✓		
Targeted Communications: Key Customers/Community Leaders/Low Income Agencies	✓		✓
Customer Information Mat'ls (e.g. Newsletter, Bill Insert)	✓		
Speakers' Bureau for Service Clubs	✓		
Updated Web Site	✓	✓	✓
Newspaper Advertising		✓	✓
Radio Advertising		✓	✓
Personal Visits: Key Customers/Community Leaders		✓	
Radio PSA Spots and Talk Show Participation			✓

2. <u>Demand-Side Management Initiatives</u>

Citizens is planning a broad spectrum of energy efficiency measures and education to address the needs of all classes of customers. The central goal of these efforts is to aggressively move forward to help customers in identifying energy efficiency opportunities that will reduce customer bills and help moderate energy demand during the peak summer months of 2001. The current plan calls for an overarching DSM effort and focused programs for residential and non-residential customers, as described below.

- **Overall DSM Elements**

Web-Site Enhancements - Citizens plans to update its Web site to include an expanded energy efficiency section featuring:

- Appliance Energy Calculator with associated efficiency recommendations;
- New appliance purchase energy considerations;
- On-line energy self audits; and

- Residential and Commercial new construction energy efficiency considerations.

Peak-Season DSM Programs - An initial high-level screening of long-term peak reduction programs will be evaluated. After the initial screening, a short list of preferred options will be selected by Citizens' management. These remaining options will be thoroughly evaluated for the purpose of developing new programs, the approval of which will be sought from the Commission Staff.

Renewable Resource Options – On-site customer options for renewable electric generation will receive priority focus in Citizens' evaluation and development of its plan to meet the Commission's Environmentally-Friendly Portfolio Standard requirements.

- **Residential DSM Initiatives**

  - A packet of energy conservation materials has been compiled for residential customers and is being offered upon request.

  - An on-line and/or mail-in energy audit program with energy efficiency recommendations will be developed for customers to perform self-audits.

  - A mail order offering of energy efficiency lighting products will be implemented. Allowing customer "on-the-bill" billing is under consideration.

  - The Good Cents residential New Construction program will continue, but is being evaluated to determine the feasibility of including a special rating for homes that utilize renewable resources.

  - A limited-time targeted incentive program will be offered for upgrades to high efficiency air conditioning units.

- **Commercial DSM Initiatives**

  - A detailed book of energy conservation measures developed specifically for Commercial Customers is available upon request. A summary of the "low-cost, no-cost" measures with the greatest potential impact will be developed and included in future mailings to Commercial Customers.

  - Over 600 commercial customer facilities were audited in the 1994-1997 time period. Recommendations made to the customers at the time of the audit may not have been implemented. The original audit reports will be provided to the customer again with a cover letter quantifying the potential savings computed at Citizens' current rates.

  - Three levels of commercial auditors will be available to evaluate and make energy efficiency recommendations for commercial facilities. The level of the auditor's technical knowledge will be matched with the customer's needs at the time of a customer on-site audit request.

  - Reference information to assist customers in working with performance contractors will be developed to provide the customers the ability to identify opportunities for alternative financing options with positive cash flow.

  - Arrangement for an energy efficiency review of proposed expansion plans for several industrial customers.

  - A packet of prescriptive measures for Commercial New Construction customers to consider will be developed for distribution by Citizens' Engineering Department.

3. <u>Customer Payment Terms and Arrangements</u>

Citizens is planning a number of initiatives targeted toward assisting customers in paying the higher electric bills that will result from increased power costs. These initiatives fall in three areas: a) Enhanced and Expanded Payment Options; b) Existing Low-Income Programs; and c) New Low-Income Outreach Efforts.

a) <u>Enhanced and Expanded Payment Options</u>

Citizens is planning initiatives to both enhance the terms of existing payment options and to add new options. With respect to existing payment options, Citizens is considering the following actions:

- **Levelized Billing**
  - ➢ expand communications efforts about the availability of Levelized Billing;
  - ➢ extend Levelized Billing to Small Commercial customers;
  - ➢ liberalize sign-up criteria by allowing up to 2 historical non-pay disconnects in 12-month period (current is 0 disconnects).
- **Payment Arrangement Flexibility**
  - ➢ extend the time period between disconnect notice and actual disconnect as special circumstances dictate;
  - ➢ allow for monthly payments scheduled to coincide with the number and date of paychecks received by customers;
  - ➢ waive 1-1/2% late payment fees in special circumstances; and
  - ➢ increase low-income agency referrals.
- **Credit Card Acceptance**
  - ➢ Citizens is exploring with vendors the option of allowing credit card payment of bills for customers who agree to a nominal service fee.

By and large, these modifications of Citizens' payment options can be accomplished within the context of its existing Rules and Regulations tariff. However, in its current form, Citizens' tariff allows for Levelized Billing only for residential customers. Consequently, Citizens asks that the Commission provide specific authority to extend Levelized Billing services to small commercial customers for a period of 12 months, following the issuance of an order in this matter.

b) Existing Low-Income Programs

Citizens' chief low-income assistance program is its CARES Residential tariff that provides bill discounts to qualifying low-income customers. Feedback from Citizens' frontline customer operations indicates that a number of eligible customers are not now taking advantage of the discounted rate. In preparation for the pending bill increases, Citizens plans to undertake a joint effort with the Low-Income Agencies to expand communications on the availability of the program to increase eligible customer participation.

c) New Low-Income Outreach Efforts

In addition, Citizens will establish a low-income electricity assistance fund to supplement existing governmental programs and work with one or more agencies to administer distribution of funds to qualifying low-income residential customers. Citizens will direct $100,000 to the fund, distributed in an equitable manner among its three operating districts. The administering agency will identify assistance candidates and track assistance to avoid duplicative payments. Citizens will credit customers' accounts on the basis of qualification forms received from the administering agency for disadvantaged customers. Citizens is now in the process of establishing agency relationships and the policies and criteria by which the funds will be distributed to customers. Citizens expects these arrangements to be finalized in concert with the implementation of the PPFAC adjustor resulting from this filing.

X. SUMMARY

As described throughout this application, the AED is experiencing unprecedented increases in the cost of purchased power, that are beyond its control. Application of the traditional PPFAC mechanism would require a substantial increase in the current rate adjustment factor. Citizens does not believe that is in the best interest of our customers. Accordingly, Citizens is requesting a non-traditional solution to the current situation. Citizens respectfully requests Commission approval to:

- Cease immediately the current (0.553) cents-per-kWh factor;
- Freeze the existing PPFAC Bank as of September 30, 2000, and amortize over 36 months;
- Create a new PPFAC Bank as of October 1, 2000, based on a phased-in, rolling 12-month average cost of power;
- Accrue carrying charges on both Bank balances, net of related deterred income tax benefits, computed at a 6% interest rate;
- Charge a PPFAC factor each month based on the sum of the factor necessary to fully amortize the frozen Bank over 36 months, plus the factor for the new Bank based on the difference between the phased-in 12-month average cost of power supply and the 5.194 cents-per-kWh base cost of power supply;
- Approve Citizens' request to implement energy risk management incentives;
- Identify and establish the criteria by which the prudence of Citizens' energy risk management initiatives will be evaluated for cost recovery purposes. (Specifically, answer the questions asked in this filing.)
- Issue whatever approvals are needed in connection with Citizens' proposed billing initiatives:
    - Allow customers to use credit cards;
    - Expand eligibility for level pay to small commercial customers;
    - Approve expanded DSM programs; and
    - Relax late payment and service shut-off criteria.

Expedited Approval. Due to the magnitude of power supply costs being proposed for deferral, plus the fact that the outcome of this application has significant implications for the AED and its customers as they prepare for the introduction of retail electric competition, Citizens respectfully requests that this application be considered on an expedited basis.

RESPECTFULLY SUBMITTED on September 28, 2000.

Craig A. Marks
Associate General Counsel
Citizens Communications Company
2901 N. Central Avenue, Suite 1660
Phoenix, Arizona 85012

Original and ten copies filed this
September 28, 2000, with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Copies of the foregoing mailed/delivered
this September 28, 2000, to:

Deborah R. Scott
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Jerry Rudibaugh
Chief Administrative Law Judge
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Lyn Farmer
Chief Counsel
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Lindy Funkhouser
Residential Utility Consumer Office
2828 North Central Avenue, Suite 1200
Phoenix, Arizona 85004

By: Joann Zychlewicz
Joann Zychlewicz

G:\Craig~docs\PPFAC\Application 9~28~00.doc

EXHIBIT NO. 1

EXHIBIT NO. 1

CITIZENS UTILITIES COMPANY
ARIZONA ELECTRIC DIVISION
PURCHASED POWER AND FUEL ADJUSTOR
BANK BALANCE REPORT FA-1
For the Month of May 2000

Line No.				
1	Ending Balance - Prior Month	(Over-collected)		$ (2,202,722)
2	Jurisdictional Sales	85,650,223		
3	Actual Cost of Generated and Purchased Power	9,818,131		
4	Unit Cost of Power ($/kWh) (line 3 / line 2)		0.114631	
5	Authorized Base Cost of Power ($/kWh)	0.051940		
6	Authorized Purchased Power Adjustor ($/kWh)	(0.005530)		
7	Net Power Costs Billed Customers ($/kWh) (line 5 + line 6)		0.046410	
8	(Over) / Under-recovery of Power Supply Costs ($/kWh) (line 4 - line 7)		0.068221	
9	Net Increase / (Decrease) in Bank Balance (line 2 X line 8)			5,843,144
10	Adjustments to Bank Balance: Computational Roundings			(40)
11	Ending Bank Balance - Current Month (line 1 + line 9 + line 10)			$ 3,640,382
				Under-collected

EXHIBIT NO. 2

Arizona Electric Division
Analysis of PPFAC Bank - Assuming No Change to Current Scheduled PPFAC Rates

Month:	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00
Beg. Balance	(2,202,700)	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	53,391,142
Power Supply Costs	9,818,131	16,430,792	19,492,731	21,566,000	13,106,000	5,361,619	4,666,197
Sales (kWh)	85,650,223	112,423,491	127,048,000	126,000,000	107,700,000	91,500,000	86,600,000
Recoveries:							
Base Rates @ $.05194	4,448,673	5,839,276	6,598,873	6,544,440	5,593,938	4,752,510	4,498,004
PPFAC Factor	(0.00553)	(0.00553)	(0.00553)	(0.00553)	(0.00553)	(0.00553)	(0.00553)
PPFAC Recoveries	(473,646)	(621,702)	(702,575)	(696,780)	(595,581)	(505,995)	(478,898)
Total	3,975,027	5,217,574	5,896,298	5,847,660	4,998,357	4,246,515	4,019,106
Ending Balance	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	53,391,142	54,038,233

Month:	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01
Beg. Balance	54,038,233	54,258,364	54,378,258	55,044,686	55,215,382	56,016,395
Power Supply Costs	4,534,388	4,443,945	4,961,097	4,475,159	5,203,416	5,508,839
Sales (kWh)	88,100,000	88,300,000	87,700,000	87,900,000	89,900,000	97,800,000
Recoveries:						
Base Rates @ $.05194	4,575,914	4,586,302	4,555,138	4,565,526	4,669,406	5,079,732
PPFAC Factor	(0.00297)	(0.00297)	(0.00297)	(0.00297)	(0.00297)	(0.00297)
PPFAC Recoveries	(261,657)	(262,251)	(260,469)	(261,063)	(267,003)	(290,466)
Total	4,314,257	4,324,051	4,294,669	4,304,463	4,402,403	4,789,266
Ending Balance	54,258,364	54,378,258	55,044,686	55,215,382	56,016,395	56,735,968

EXHIBIT NO. 3

Arizona Electric Division
Analysis of PPFAC Bank - Assuming Suspension of Current PPFAC Factor

Month:	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00
Beg. Balance	(2,202,700)	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	52,885,147
Power Supply Costs	9,818,131	16,430,792	19,492,731	21,566,000	13,106,000	5,361,619	4,666,197
Sales (kWh)	85,650,223	112,423,491	127,048,000	126,000,000	107,700,000	91,500,000	86,600,000
Recoveries:							
Base Rates @ $.05194	4,448,673	5,839,276	6,598,873	6,544,440	5,593,938	4,752,510	4,498,004
PPFAC Factor	(0.00553)	(0.00553)	(0.00553)	(0.00553)	(0.00553)	-	-
PPFAC Recoveries	(473,646)	(621,702)	(702,575)	(696,780)	(595,581)	-	-
Total	3,975,027	5,217,574	5,896,298	5,847,660	4,998,357	4,752,510	4,498,004
Ending Balance	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	52,885,147	53,053,340

Month:	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01
Beg. Balance	53,053,340	53,011,814	52,869,457	53,275,416	53,185,049	53,719,059
Power Supply Costs	4,534,388	4,443,945	4,961,097	4,475,159	5,203,416	5,508,839
Sales (kWh)	88,100,000	88,300,000	87,700,000	87,900,000	89,900,000	97,800,000
Recoveries:						
Base Rates @ $.05194	4,575,914	4,586,302	4,555,138	4,565,526	4,669,406	5,079,732
PPFAC Factor	-	-	-	-	-	-
PPFAC Recoveries	-	-	-	-	-	-
Total	4,575,914	4,586,302	4,555,138	4,565,526	4,669,406	5,079,732
Ending Balance	53,011,814	52,869,457	53,275,416	53,185,049	53,719,059	54,148,166

EXHIBIT NO. 4

Arizona Electric Division
Analysis of PPFAC Bank - Full Bank Recovery by May, 2001

Month:	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00
Beg. Balance	(2,202,700)	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	45,983,302
Power Supply Costs	9,818,131	16,430,792	19,492,731	21,566,000	13,106,000	5,361,619	4,666,197
Sales (kWh)	85,650,223	112,423,491	127,048,000	126,000,000	107,700,000	91,500,000	86,600,000
Recoveries:							
Base Rates @ $.05194	4,448,673	5,839,276	6,598,873	6,544,440	5,593,938	4,752,510	4,498,004
PPFAC Factor	(0.00553)	(0.00553)	(0.00553)	(0.00553)	(0.00553)	0.07543	0.07543
PPFAC Recoveries	(473,646)	(621,702)	(702,575)	(696,780)	(595,581)	6,901,845	6,532,238
Total	3,975,027	5,217,574	5,896,298	5,847,660	4,998,357	11,654,355	11,030,242
Ending Balance	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	45,983,302	39,619,257

Month:	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01
Beg. Balance	39,619,257	32,932,348	26,129,522	19,920,270	13,199,606	6,952,459
Power Supply Costs	4,534,388	4,443,945	4,961,097	4,475,159	5,203,416	5,508,839
Sales (kWh)	88,100,000	88,300,000	87,700,000	87,900,000	89,900,000	97,800,000
Recoveries:						
Base Rates @ $.05194	4,575,914	4,586,302	4,555,138	4,565,526	4,669,406	5,079,732
PPFAC Factor	0.07543	0.07543	0.07543	0.07543	0.07543	0.07543
PPFAC Recoveries	6,645,383	6,660,469	6,615,211	6,630,297	6,781,157	7,377,054
Total	11,221,297	11,246,771	11,170,349	11,195,823	11,450,563	12,456,786
Ending Balance	32,932,348	26,129,522	19,920,270	13,199,606	6,952,459	4,512

EXHIBIT NO. 5

Arizona Electric Division
Analysis of PPFAC Banks - PGA Method

Month:	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01
Existing Bank:										
Beg. Balance	(2,202,700)	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	47,889,528	43,737,924	39,514,410	35,281,308
Power Supply Costs	9,818,131	16,430,792	19,492,731	21,566,000	13,106,000	-	-	-	-	-
Sales (kWh)	85,650,223	112,423,491	127,048,000	126,000,000	107,700,000	91,500,000	86,600,000	88,100,000	88,300,000	87,700,000
Recoveries:										
Base Rates @ $.05194	4,448,673	5,839,276	6,598,873	6,544,440	5,593,938	-	-	-	-	-
PPFAC Factor	(0.00553)	(0.00553)	(0.00553)	(0.00553)	(0.00553)	0.04794	0.04794	0.04794	0.04794	0.04794
PPFAC Recoveries	(473,646)	(621,702)	(702,575)	(696,780)	(595,581)	4,386,510	4,151,604	4,223,514	4,233,102	4,204,338
Total	3,975,027	5,217,574	5,896,298	5,847,660	4,998,357	4,386,510	4,151,604	4,223,514	4,233,102	4,204,338
Ending Balance	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	47,889,528	43,737,924	39,514,410	35,281,308	31,076,970
New Bank:										
Beg Balance						0	(282)	(210,801)	(498,167)	(790,477)
Power Supply Costs						5,361,619	4,666,197	4,534,388	4,443,945	4,961,097
Sales (kWh)						91,500,000	86,600,000	88,100,000	88,300,000	87,700,000
Recoveries:										
Base Rates @ $.05194						4,752,510	4,498,004	4,575,914	4,586,302	4,555,138
Phased-in 12-month Rolling Average Cost of Power						0.05860	0.05630	0.05470	0.05359	0.05418
PPFAC Factor (Avg. costs - $.05194)						0.00666	0.00436	0.00276	0.00165	0.00224
PPFAC Recoveries						609,390	377,576	243,156	145,695	196,448
Total						5,361,900	4,875,580	4,819,070	4,731,997	4,751,586
Ba;lance Before Interest						(281)	(209,666)	(495,483)	(786,219)	(580,967)
Interest at 6.50%						(2)	(1,136)	(2,684)	(4,259)	(3,147)
Ending Balance						(282)	(210,801)	(498,167)	(790,477)	(584,114)
Total - Both Banks						47,889,246	43,527,123	39,016,243	34,490,831	30,492,856
Total PPFAC Rate ($/kwh)						0.05460	0.05230	0.05070	0.04959	0.05018

Arizona Electric Division
Analysis of PPFAC Banks - PGA Method

Month:	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01
Existing Bank:							
Beg. Balance	31,076,970	26,863,044	22,553,238	17,864,706	17,915,220	11,673,432	5,378,910
Power Supply Costs	-	-	-	-	-	-	-
Sales (kWh)	87,900,000	89,900,000	97,800,000	111,400,000	130,200,000	131,300,000	112,200,000
Recoveries:							
Base Rates @ $.05194	-	-	-	-	-	-	-
PPFAC Factor	0.04794	0.04794	0.04794	0.04794	0.04794	0.04794	0.04794
PPFAC Recoveries	4,213,926	4,309,806	4,688,532	5,340,516	6,241,788	6,294,522	5,378,868
Total	4,213,926	4,309,806	4,688,532	5,340,516	6,241,788	6,294,522	5,378,868
Ending Balance	26,863,044	22,553,238	17,864,706	12,524,190	11,673,432	5,378,910	42
New Bank:							
Beg Balance	(584,114)	(828,374)	(504,752)	(330,729)	8,172,753	16,281,793	27,416,125
Power Supply Costs	4,475,159	5,203,416	5,508,839	15,847,500	17,915,220	22,467,500	13,663,500
Sales (kWh)	87,900,000	89,900,000	97,800,000	111,400,000	130,200,000	131,300,000	112,200,000
Recoveries:							
Base Rates @ $.05194	4,565,526	4,669,406	5,079,732	5,786,116	6,762,588	6,819,722	5,827,668
Phased-in 12-month Rolling Average Cost of Power	0.05364	0.05425	0.05453	0.06632	0.07599	0.08744	0.09065
PPFAC Factor (Avg. costs - $.05194)	0.00170	0.00231	0.00259	0.01438	0.02405	0.03550	0.03871
PPFAC Recoveries	149,430	207,669	253,302	1,601,932	3,131,310	4,661,150	4,343,262
Total	4,714,956	4,877,075	5,333,034	7,388,048	9,893,898	11,480,872	10,170,930
Ba;lance Before Interest	(823,911)	(502,033)	(328,947)	8,128,723	16,194,075	27,268,421	30,908,695
Interest at 6.50%	(4,463)	(2,719)	(1,782)	44,031	87,718	147,704	167,422
Ending Balance	(828,374)	(504,752)	(330,729)	8,172,753	16,281,793	27,416,125	31,076,117
Total - Both Banks	26,034,670	22,048,485	17,533,977	20,696,943	27,955,225	32,795,035	31,076,159
Total PPFAC Rate ($/kwh)	0.04964	0.05025	0.05053	0.06232	0.07199	0.08344	0.08665

EXHIBIT NO. 6

EXHIBIT NO. 6

Arizona Electric Utilities
Comparison of Residential Rates

Utility	Summer (May-Oct.) Bills			Winter (Nov. - April) Bills			Total Average Monthly Bills		
	500 kWh	1,000 kWh	1,500 kWh	500 kWh	1,000 kWh	1,500 kWh	500 kWh	1,000 kWh	1,500 kWh
Duncan Valley	32.55	43.55	54.55	32.55	43.55	54.55	32.55	43.55	54.55
CUC - MED	41.18	75.87	110.55	41.18	75.87	110.55	41.18	75.87	110.55
CUC - SCED	43.38	80.27	117.15	43.38	80.27	117.15	43.38	80.27	117.15
Garkane Electric Co-op	44.04	75.57	107.11	44.04	75.57	107.11	44.04	75.57	107.11
Graham County Electric Co-op	45.70	83.39	121.09	45.70	83.39	121.09	45.70	83.39	121.09
TEP	50.36	95.82	141.28	44.39	83.87	123.36	47.38	89.85	132.32
APS	49.36	107.04	170.12	46.40	85.29	124.19	47.88	96.17	147.16
Mohave Electric Co-op	48.10	86.69	125.29	48.10	86.69	125.29	48.10	86.69	125.29
Navapache Electric Co-op	53.15	95.04	136.94	53.15	95.04	136.94	53.15	95.04	136.94
Sulphur Springs	54.25	99.84	144.26	54.25	99.84	144.26	54.25	99.84	144.26
Trico Electric	55.15	102.30	149.45	55.15	102.30	149.45	55.15	102.30	149.45

Note: The above reflect current PPFAC adjustors, but do not include sales taxes or ACC/RUCO assessments.

EXHIBIT NO. 7

Arizona Electric Division
Analysis of PPFAC Banks - Proposed Modified PGA Method

Month:	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00
Existing Bank:							
Beg. Balance	(2,202,700)	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	51,086,532
Power Supply Costs	9,818,131	16,430,792	19,492,731	21,566,000	13,106,000	-	-
Sales (kWh)	85,650,223	112,423,491	127,048,000	126,000,000	107,700,000	91,500,000	86,600,000
Recoveries:							
Base Rates @ $.05194	4,448,673	5,839,276	6,598,873	6,544,440	5,593,938	-	-
PPFAC Factor	(0.00553)	(0.00553)	(0.00553)	(0.00553)	(0.00553)	0.014690	0.014690
PPFAC Recoveries	(473,646)	(621,702)	(702,575)	(696,780)	(595,581)	1,344,135	1,272,154
Total	3,975,027	5,217,574	5,896,298	5,847,660	4,998,357	1,344,135	1,272,154
Balance Before Interest	3,640,404	14,853,622	28,450,055	44,168,395	52,276,038	50,931,903	49,814,378
A.D.I.T. @ 39.28%						(20,006,051)	(19,567,088)
Balance For Interest						30,925,851	30,247,290
Interest @ 6%						154,629	151,236
Ending Balance						51,086,532	49,965,615
New Bank:							
Beg Balance						0	-
Power Supply Costs						5,361,619	4,666,197
Sales (kWh)						91,500,000	86,600,000
Recoveries:							
Base Rates @ $.05194						4,752,510	4,498,004
Rolling Average Cost of Power						0.05860	0.05630
PPFAC Factor (Avg. costs - $.05194)						0.00666	0.00436
PPFAC Recoveries						609,109	377,958
Total						5,361,619	4,875,962
Ba;lance Before Interest						$ -	$ (209,765)
A.D.I.T. @ 39.28%						$ -	$ -
Balance For Interest						$ -	(209,765)
Interest @ 6%						-	(1,049)
Ending Balance						$ -	(210,814)
Old Bank Ending Balance						51,086,532	49,965,615
Total - Both Banks						51,086,532	49,754,800
Total PPFAC Rate ($/kwh)						0.02135	0.01905

Arizona Electric Division
Analysis of PPFAC Banks

Month:	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01
Existing Bank:								
Beg. Balance	49,965,615	48,819,192	47,666,342	46,518,833	45,364,893	44,177,980	42,871,061	41,359,783
Power Supply Costs	-	-	-	-	-	-	-	-
Sales (kWh)	88,100,000	88,300,000	87,700,000	87,900,000	89,900,000	97,800,000	111,400,000	130,200,000
Recoveries:								
Base Rates @ $.05194	-	-	-	-	-	-	-	-
PPFAC Factor	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690
PPFAC Recoveries	1,294,189	1,297,127	1,288,313	1,291,251	1,320,631	1,436,682	1,636,466	1,912,638
Total	1,294,189	1,297,127	1,288,313	1,291,251	1,320,631	1,436,682	1,636,466	1,912,638
Balance Before Interest	48,671,426	47,522,065	46,378,029	45,227,582	44,044,262	42,741,298	41,234,595	39,447,145
A.D.I.T. @ 39.28%	(19,118,136)	(18,666,667)	(18,217,290)	(17,765,394)	(17,300,586)	(16,788,782)	(16,196,949)	(15,494,839)
Balance For Interest	29,553,290	28,855,398	28,160,739	27,462,188	26,743,676	25,952,516	25,037,646	23,952,306
Interest @ 6%	147,766	144,277	140,804	137,311	133,718	129,763	125,188	119,762
Ending Balance	48,819,192	47,666,342	46,518,833	45,364,893	44,177,980	42,871,061	41,359,783	39,566,906
New Bank:								
Beg Balance	(210,814)	(497,273)	(786,766)	(576,207)	(817,204)	(489,231)	(312,547)	8,189,202
Power Supply Costs	4,534,388	4,443,945	4,961,097	4,475,159	5,203,416	5,508,839	15,847,500	17,915,220
Sales (kWh)	88,100,000	88,300,000	87,700,000	87,900,000	89,900,000	97,800,000	111,400,000	130,200,000
Recoveries:								
Base Rates @ $.05194	4,575,914	4,586,302	4,555,138	4,565,526	4,669,406	5,079,732	5,786,116	6,762,588
Rolling Average Cost of Power	0.05470	0.05359	0.05418	0.05364	0.05425	0.05453	0.06632	0.07599
PPFAC Factor (Avg. costs - $.05194)	0.00276	0.00165	0.00224	0.00170	0.00231	0.00259	0.01438	0.02405
PPFAC Recoveries	243,508	145,695	196,448	149,430	207,669	253,302	1,601,932	3,131,310
Total	4,819,422	4,731,997	4,751,586	4,714,956	4,877,075	5,333,034	7,388,048	9,893,898
Ba;lance Before Interest	$ (494,799)	$ (782,851)	$ (573,341)	$ (813,138)	$ (486,797)	$ (310,992)	$ 8,148,460	$ 16,169,782
A.D.I.T. @ 39.28%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Balance For Interest	(494,799)	(782,851)	(573,341)	(813,138)	(486,797)	(310,992)	8,148,460	16,169,782
Interest @ 6%	(2,474)	(3,914)	(2,867)	(4,066)	(2,434)	(1,555)	40,742	80,849
Ending Balance	(497,273)	(786,766)	(576,207)	(817,204)	(489,231)	(312,547)	8,189,202	16,250,631
Old Bank Ending Balance	48,819,192	47,666,342	46,518,833	45,364,893	44,177,980	42,871,061	41,359,783	39,566,906
Total - Both Banks	48,321,919	46,879,577	45,942,626	44,547,689	43,688,749	42,558,514	49,548,985	55,817,537
Total PPFAC Rate ($/kwh)	0.01745	0.01634	0.01693	0.01639	0.01700	0.01728	0.02907	0.03874

Arizona Electric Division
Analysis of PPFAC Banks

Month:	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	Feb-02
Existing Bank:							
Beg. Balance	39,566,906	37,752,379	36,213,773	34,919,511	33,696,466	32,447,605	31,192,007
Power Supply Costs	-	-	-	-	-	-	-
Sales (kWh)	131,300,000	112,200,000	95,300,000	90,200,000	91,700,000	91,900,000	91,300,000
Recoveries:							
Base Rates @ $.05194	-	-	-	-	-	-	-
PPFAC Factor	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690
PPFAC Recoveries	1,928,797	1,648,218	1,399,957	1,325,038	1,347,073	1,350,011	1,341,197
Total	1,928,797	1,648,218	1,399,957	1,325,038	1,347,073	1,350,011	1,341,197
Balance Before Interest	37,638,109	36,104,161	34,813,816	33,594,473	32,349,393	31,097,594	29,850,810
A.D.I.T. @ 39.28%	(14,784,249)	(14,181,714)	(13,674,867)	(13,195,909)	(12,706,841)	(12,215,135)	(11,725,398)
Balance For Interest	22,853,860	21,922,446	21,138,949	20,398,564	19,642,551	18,882,459	18,125,412
Interest @ 6%	114,269	109,612	105,695	101,993	98,213	94,412	90,627
Ending Balance	37,752,379	36,213,773	34,919,511	33,696,466	32,447,605	31,192,007	29,941,437
New Bank:							
Beg Balance	16,250,631	27,292,192	23,782,159	27,117,758	30,692,143	34,437,941	38,211,714
Power Supply Costs	22,467,500	13,663,500	5,286,586	4,555,987	4,492,826	4,459,942	4,897,111
Sales (kWh)	131,300,000	112,200,000	95,300,000	90,200,000	91,700,000	91,900,000	91,300,000
Recoveries:							
Base Rates @ $.05194	6,819,722	5,827,668	4,949,882	4,684,988	4,762,898	4,773,286	4,742,122
Rolling Average Cost of Power	0.08744	0.09065	0.09030	0.08994	0.08964	0.08939	0.08908
PPFAC Factor (Avg. costs - $.05194)	0.03550	0.03871	0.03836	0.03800	0.03770	0.03745	0.03714
PPFAC Recoveries	4,661,150	4,343,262	3,655,708	3,427,600	3,457,090	3,441,655	3,390,882
Total	11,480,872	10,170,930	8,605,590	8,112,588	8,219,988	8,214,941	8,133,004
Ba;lance Before Interest	$27,156,410	$23,663,840	$ 26,982,844	$ 30,539,446	$ 34,266,608	$ 38,021,606	$ 41,257,499
A.D.I.T. @ 39.28%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Balance For Interest	27,156,410	23,663,840	26,982,844	30,539,446	34,266,608	38,021,606	41,257,499
Interest @ 6%	135,782	118,319	134,914	152,697	171,333	190,108	206,287
Ending Balance	27,292,192	23,782,159	27,117,758	30,692,143	34,437,941	38,211,714	41,463,786
Old Bank Ending Balance	37,752,379	36,213,773	34,919,511	33,696,466	32,447,605	31,192,007	29,941,437
Total - Both Banks	65,044,571	59,995,932	62,037,269	64,388,608	66,885,546	69,403,721	71,405,223
Total PPFAC Rate ($/kwh)	0.05019	0.05340	0.05305	0.05269	0.05239	0.05214	0.05183

Arizona Electric Division
Analysis of PPFAC Banks

Month:	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02
Existing Bank:								
Beg. Balance	29,941,437	28,682,650	27,390,572	25,972,274	24,340,439	22,416,325	20,470,161	18,809,834
Power Supply Costs	-	-	-	-	-	-	-	-
Sales (kWh)	91,600,000	93,600,000	101,900,000	116,100,000	135,600,000	136,700,000	116,900,000	99,300,000
Recoveries:								
Base Rates @ $.05194	-	-	-	-	-	-	-	-
PPFAC Factor	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690
PPFAC Recoveries	1,345,604	1,374,984	1,496,911	1,705,509	1,991,964	2,008,123	1,717,261	1,458,717
Total	1,345,604	1,374,984	1,496,911	1,705,509	1,991,964	2,008,123	1,717,261	1,458,717
Balance Before Interest	28,595,833	27,307,666	25,893,661	24,266,765	22,348,475	20,408,202	18,752,900	17,351,117
A.D.I.T. @ 39.28%	(11,232,443)	(10,726,451)	(10,171,030)	(9,531,985)	(8,778,481)	(8,016,342)	(7,366,139)	(6,815,519)
Balance For Interest	17,363,390	16,581,215	15,722,631	14,734,780	13,569,994	12,391,860	11,386,761	10,535,598
Interest @ 6%	86,817	82,906	78,613	73,674	67,850	61,959	56,934	52,678
Ending Balance	28,682,650	27,390,572	25,972,274	24,340,439	22,416,325	20,470,161	18,809,834	17,403,795
New Bank:								
Beg Balance	41,463,786	45,117,714	48,220,877	51,754,896	45,488,569	38,824,915	27,546,863	23,710,863
Power Supply Costs	4,501,080	5,201,491	5,475,219	16,501,875	18,650,085	23,386,875	14,233,875	5,711,735
Sales (kWh)	91,600,000	93,600,000	101,900,000	116,100,000	135,600,000	136,700,000	116,900,000	99,300,000
Recoveries:								
Base Rates @ $.05194	4,757,704	4,861,584	5,292,686	6,030,234	7,043,064	7,100,198	6,071,786	5,157,642
Rolling Average Cost of Power	0.08883	0.08856	0.08824	0.08843	0.08864	0.08899	0.08911	0.08917
PPFAC Factor (Avg. costs - $.05194)	0.03689	0.03662	0.03630	0.03649	0.03670	0.03705	0.03717	0.03723
PPFAC Recoveries	3,379,124	3,427,632	3,698,970	4,236,489	4,976,520	5,064,735	4,345,173	3,696,939
Total	8,136,828	8,289,216	8,991,656	10,266,723	12,019,584	12,164,933	10,416,959	8,854,581
Ba;lance Before Interest	$ 44,893,247	$ 47,980,973	$ 51,497,409	$ 45,262,257	$ 38,631,756	$ 27,409,814	$ 23,592,898	$ 26,735,744
A.D.I.T. @ 39.28%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Balance For Interest	44,893,247	47,980,973	51,497,409	45,262,257	38,631,756	27,409,814	23,592,898	26,735,744
Interest @ 6%	224,466	239,905	257,487	226,311	193,159	137,049	117,964	133,679
Ending Balance	45,117,714	48,220,877	51,754,896	45,488,569	38,824,915	27,546,863	23,710,863	26,869,423
Old Bank Ending Balance	28,682,650	27,390,572	25,972,274	24,340,439	22,416,325	20,470,161	18,809,834	17,403,795
Total - Both Banks	73,800,363	75,611,449	77,727,170	69,829,007	61,241,240	48,017,024	42,520,697	44,273,218
Total PPFAC Rate ($/kwh)	0.05158	0.05131	0.05099	0.05118	0.05139	0.05174	0.05186	0.05192

Arizona Electric Division
Analysis of PPFAC Banks

Month:	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03
Existing Bank:							
Beg. Balance	17,403,795	16,073,054	14,716,171	13,350,748	11,990,021	10,622,215	9,217,841
Power Supply Costs	-	-	-	-	-	-	-
Sales (kWh)	93,900,000	95,400,000	95,700,000	95,100,000	95,300,000	97,500,000	106,100,000
Recoveries:							
Base Rates @ $.05194	-	-	-	-	-	-	-
PPFAC Factor	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690	0.014690
PPFAC Recoveries	1,379,391	1,401,426	1,405,833	1,397,019	1,399,957	1,432,275	1,558,609
Total	1,379,391	1,401,426	1,405,833	1,397,019	1,399,957	1,432,275	1,558,609
Balance Before Interest	16,024,404	14,671,628	13,310,338	11,953,729	10,590,064	9,189,940	7,659,232
A.D.I.T. @ 39.28%	(6,294,386)	(5,763,015)	(5,228,301)	(4,695,425)	(4,159,777)	(3,609,808)	(3,008,546)
Balance For Interest	9,730,018	8,908,612	8,082,037	7,258,304	6,430,287	5,580,132	4,650,686
Interest @ 6%	48,650	44,543	40,410	36,292	32,151	27,901	23,253
Ending Balance	16,073,054	14,716,171	13,350,748	11,990,021	10,622,215	9,217,841	7,682,485
New Bank:							
Beg Balance	26,869,423	30,631,735	34,530,955	38,447,855	41,892,798	45,689,553	48,972,273
Power Supply Costs	4,608,811	4,588,340	4,581,060	4,978,419	4,631,331	5,319,720	5,479,266
Sales (kWh)	93,900,000	95,400,000	95,700,000	95,100,000	95,300,000	97,500,000	106,100,000
Recoveries:							
Base Rates @ $.05194	4,877,166	4,955,076	4,970,658	4,939,494	4,949,882	5,064,150	5,510,834
Rolling Average Cost of Power	0.08895	0.08876	0.08859	0.08839	0.08824	0.08806	0.08778
PPFAC Factor (Avg. costs - $.05194)	0.03701	0.03682	0.03665	0.03645	0.03630	0.03612	0.03584
PPFAC Recoveries	3,475,239	3,513,084	3,507,815	3,466,729	3,459,315	3,521,958	3,802,375
Total	8,352,405	8,468,160	8,478,473	8,406,223	8,409,197	8,586,108	9,313,209
Ba;lance Before Interest	$ 30,479,338	$ 34,359,159	$ 38,256,572	$ 41,684,376	$ 45,462,242	$ 48,728,630	$ 52,562,572
A.D.I.T. @ 39.28%	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Balance For Interest	30,479,338	34,359,159	38,256,572	41,684,376	45,462,242	48,728,630	52,562,572
Interest @ 6%	152,397	171,796	191,283	208,422	227,311	243,643	262,813
Ending Balance	30,631,735	34,530,955	38,447,855	41,892,798	45,689,553	48,972,273	52,825,385
Old Bank Ending Balance	16,073,054	14,716,171	13,350,748	11,990,021	10,622,215	9,217,841	7,682,485
Total - Both Banks	46,704,789	49,247,126	51,798,603	53,882,819	56,311,769	58,190,114	60,507,870
Total PPFAC Rate ($/kwh)	0.05170	0.05151	0.05134	0.05114	0.05099	0.05081	0.05053

Arizona Electric Division
Analysis of PPFAC Banks

Month:	Jun-03	Jul-03	Aug-03	Sep-03
Existing Bank:				
Beg. Balance	7,682,485	5,925,870	3,864,809	1,778,335
Power Supply Costs	-	-	-	-
Sales (kWh)	120,800,000	141,100,000	142,400,000	121,700,000
Recoveries:				
Base Rates @ $.05194	-	-	-	-
PPFAC Factor	0.014690	0.014690	0.014690	0.014690
PPFAC Recoveries	1,774,552	2,072,759	2,091,856	1,787,773
Total	1,774,552	2,072,759	2,091,856	1,787,773
Balance Before Interest	5,907,933	3,853,111	1,772,953	(9,438)
A.D.I.T. @ 39.28%	(2,320,636)	(1,513,502)	(696,416)	3,707
Balance For Interest	3,587,297	2,339,609	1,076,537	(5,731)
Interest @ 6%	17,936	11,698	5,383	(29)
Ending Balance	5,925,870	3,864,809	1,778,335	(9,466)
New Bank:				
Beg Balance	52,825,385	54,805,933	56,712,483	57,955,353
Power Supply Costs	7,775,959	8,311,579	7,252,845	6,372,716
Sales (kWh)	120,800,000	141,100,000	142,400,000	121,700,000
Recoveries:				
Base Rates @ $.05194	6,274,352	7,328,734	7,396,256	6,321,098
Rolling Average Cost of Power	0.08068	0.07235	0.05962	0.05337
PPFAC Factor (Avg. costs - $.05194)	0.02874	0.02041	0.00768	0.00143
PPFAC Recoveries	3,472,301	2,879,910	1,093,276	174,151
Total	9,746,653	10,208,644	8,489,532	6,495,249
Ba;lance Before Interest	$ 54,533,266	$ 56,430,331	$ 57,667,018	$ 57,789,551
A.D.I.T. @ 39.28%	$ -	$ -	$ -	$ -
Balance For Interest	54,533,266	56,430,331	57,667,018	57,789,551
Interest @ 6%	272,666	282,152	288,335	288,948
Ending Balance	54,805,933	56,712,483	57,955,353	58,078,499
Old Bank Ending Balance	5,925,870	3,864,809	1,778,335	(9,466)
Total - Both Banks	60,731,802	60,577,291	59,733,688	58,069,033
Total PPFAC Rate ($/kwh)	0.04343	0.03510	0.02237	0.01612